

MINOR SOURCE OPERATING PERMIT OFFICE OF AIR QUALITY

**Fayette Memorial Hospital
1941 Virginia Avenue
Connersville, Indiana 47331**

(herein known as the Permittee) is hereby authorized to construct and operate subject to the conditions contained herein, the emission units described in Section A (Source Summary) of this permit.

This permit is issued to the above mentioned company under the provisions of 326 IAC 2-1.1, 326 IAC 2-6.1 and 40 CFR 52.780, with conditions listed on the attached pages.

Operation Permit No.: MSOP 041-14812-00018	
Issued by: Original Signed by Paul Dubenetzky Paul Dubenetzky, Branch Chief Office of Air Quality	Issuance Date: February 14, 2002 Expiration Date: February 14, 2007

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SECTION A

SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.3 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-5.1-3(c)] [326 IAC 2-6.1-4(a)]

The Permittee owns and operates a stationary acute care hospital.

Authorized Individual: David Brandon, CEO
Source Address: 1941 Virginia Avenue, Connersville, Indiana 47331
Mailing Address: 1941 Virginia Avenue, Connersville, Indiana 47331
Phone Number: 765-825-5131
SIC Code: 8062
County Location: Fayette County
County Status: Attainment for all criteria pollutants
Source Status: Minor Source Operating Permit
Minor Source, under PSD;
Minor Source, Section 112 of the Clean Air Act

A.2 Emissions units and Pollution Control Equipment Summary

This stationary source is approved to construct and operate the following emissions units and pollution control devices:

- (a) One (1) natural gas-fired utility boiler (identified as Boiler No. 1), having a maximum heat input capacity of 2.5 MMBtu per hour and exhausting at stack S/V-01. This boiler was constructed in 1964 and uses No. 2 fuel oil as an alternative fuel.
- (b) Two (2) natural gas-fired utility boilers (identified as Boiler No. 2 and Boiler No. 3), each having a maximum heat input capacity of 14.6 MMBtu per hour. Boiler No. 2 exhausts at stack S/V-02 and Boiler No. 3 exhausts at stack S/V-03. Both boilers were constructed in 1994 and use No. 2 fuel oil as an alternative fuel.
- (c) One (1) natural gas-fired utility boiler (identified as Boiler No. 4), having a maximum heat input capacity of 3.0 MMBtu per hour and exhausting at stack S/V-04. This boiler uses No. 2 fuel oil as an alternative fuel.
- (d) Two (2) fuel oil storage tanks, constructed in 1998, each with a maximum storage capacity of 20,000 gallons. Both tanks are used to store No. 2 fuel oil exclusively.
- (e) Two (2) diesel powered emergency generators each having a maximum operating capacity of 1,482 Horsepower and operating for not more than 500 hours per year.

SECTION B GENERAL CONSTRUCTION CONDITIONS

THIS SECTION OF THE PERMIT IS BEING ISSUED UNDER THE PROVISIONS OF 326 IAC 2-1.1 AND 40 CFR 52.780, WITH CONDITIONS LISTED BELOW.

B.1 Permit No Defense [IC 13]

This permit to construct does not relieve the Permittee of the responsibility to comply with the provisions of the Indiana Environmental Management Law (IC 13-11 through 13-20; 13-22 through 13-25; and 13-30), the Air Pollution Control Law (IC 13-17) and the rules promulgated thereunder, as well as other applicable local, state, and federal requirements.

B.2 Definitions

Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, any applicable definitions found in IC 13-11, 326 IAC 1-2, and 326 IAC 2-1.1-1 shall prevail.

B.3 Effective Date of the Permit [IC13-15-5-3]

Pursuant to IC 13-15-5-3, this permit becomes effective upon its issuance.

B.4 Revocation of Permits [326 IAC 2-1.1-9(5)]

Pursuant to 326 IAC 2-1.1-9(5)(Revocation of Permits), the Commissioner may revoke this permit if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is suspended for a continuous period of one (1) year or more.

B.5 Modification to Permit [326 IAC 2]

Notwithstanding the Section B condition entitled "Minor Source Operating Permit", all requirements and conditions of this construction permit shall remain in effect unless modified in a manner consistent with procedures established for modifications of construction permits pursuant to 326 IAC 2 (Permit Review Rules).

B.6 Minor Source Operating Permit [326 IAC 2-6.1]

- (a) This operation permit will be subject to annual operating permit fees pursuant to 326 IAC 2-1.1-7(Fees).
- (b) Pursuant to 326 IAC 2-6.1-7, the Permittee shall apply for an operation permit renewal at least ninety (90) days prior to the expiration date of this permit. If IDEM, OAQ, upon receiving a timely and complete permit application, fails to issue or deny the permit renewal prior to the expiration date of this permit, this existing permit shall not expire and all terms and conditions shall continue in effect until the renewal permit has been issued or denied. The operation permit issued shall contain as a minimum the conditions in Section C and Section D of this permit.

B.7 NSPS Reporting Requirement

Pursuant to the New Source Performance Standards (NSPS), Part 60, Subparts Dc and Kb, the source owner/operator is hereby advised of the requirement to report the following at the appropriate times:

- (a) Commencement of construction date (no later than 30 days after such date);
- (b) Anticipated start-up date (not more than 60 days or less than 30 days prior to such date);
- (c) Actual start-up date (within 15 days after such date); and
- (d) Date of performance testing (at least 30 days prior to such date), when required by a condition elsewhere in this permit.

Reports are to be sent to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, IN 46206-6015

The application and enforcement of these standards have been delegated to the IDEM, OAQ.
The requirements of 40 CFR Part 60 are also federally enforceable.

B.8 **Permit Term [326 IAC 2-6.1-7]**

This permit is issued for a fixed term of five (5) years from the original date, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications or amendments of this permit do not affect the expiration.

SECTION C

SOURCE OPERATION CONDITIONS

Entire Source

C.1 PSD Minor Source Status [326 IAC 2-2] [40 CFR 52.21]

- (a) The total source potential to emit of all criteria pollutants is less than 250 tons per year. Therefore the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) and 40 CFR 52.21 will not apply.
- (b) Any change or modification which may increase potential to emit to 250 tons per year from this source, shall cause this source to be considered a major source under PSD, 326 IAC 2-2 and 40 CFR 52.21, and shall require approval from IDEM, OAQ prior to making the change.

C.2 Preventive Maintenance Plan [326 IAC 1-6-3]

- (a) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMP) after issuance of this permit, including the following information on each emissions unit:
 - (1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;
 - (2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions;
 - (3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.
- (b) The Permittee shall implement the Preventive Maintenance Plans as necessary to ensure that failure to implement the Preventive Maintenance Plan does not cause or contribute to a violation of any limitation on emissions or potential to emit.
- (c) PMP's shall be submitted to IDEM, OAQ, upon request and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ, may require the Permittee to revise its Preventive Maintenance Plan whenever lack of proper maintenance causes or contributes to any violation.

C.3 Permit Revision [326 IAC 2-5.1-3(e)(3)] [326 IAC 2-6.1-6]

- (a) The Permittee must comply with the requirements of 326 IAC 2-6.1-6 whenever the Permittee seeks to amend or modify this permit.
- (b) Any application requesting an amendment or modification of this permit shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

Any such application should be certified by the "authorized individual" as defined by 326 IAC 2-1.1-1.

- (c) The Permittee shall notify the OAQ within thirty (30) calendar days of implementing a notice-only change. [326 IAC 2-6.1-6(d)]

C.4 Inspection and Entry [326 IAC 2-5.1-3(e)(4)(B)] [326 IAC 2-6.1-5(a)(4)]

Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee's right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

- (a) Enter upon the Permittee's premises where a permitted source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
- (b) Have access to and copy, at reasonable times, any records that must be kept under this title or the conditions of this permit or any operating permit revisions;
- (c) Inspect, at reasonable times, any processes, emissions units (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit or any operating permit revisions;
- (d) Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and
- (e) Utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

C.5 Transfer of Ownership or Operation [326 IAC 2-6.1-6(d)(3)]

Pursuant to [326 IAC 2-6.1-6(d)(3)] :

- (a) In the event that ownership of this source is changed, the Permittee shall notify IDEM, OAQ, Permits Branch, within thirty (30) days of the change.
- (b) The written notification shall be sufficient to transfer the permit to the new owner by an notice-only change pursuant to 326 IAC 2-6.1-6(d)(3).
- (c) IDEM, OAQ, shall issue a revised permit.

The notification which shall be submitted by the Permittee does require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1.

C.6 Permit Revocation [326 IAC 2-1-9]

Pursuant to 326 IAC 2-1-9(a)(Revocation of Permits), this permit to construct and operate may be revoked for any of the following causes:

- (a) Violation of any conditions of this permit.
- (b) Failure to disclose all the relevant facts, or misrepresentation in obtaining this permit.
- (c) Changes in regulatory requirements that mandate either a temporary or permanent reduction of discharge of contaminants. However, the amendment of appropriate sections of this permit shall not require revocation of this permit.
- (d) Noncompliance with orders issued pursuant to 326 IAC 1-5 (Episode Alert Levels) to reduce emissions during an air pollution episode.
- (e) For any cause which establishes in the judgment of IDEM, the fact that continuance of this permit is not consistent with purposes of this article.

C.7 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

- (a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.
- (b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

C.8 Stack Height [326 IAC 1-7]

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted by using good engineering practices (GEP) pursuant to 326 IAC 1-7-3.

Testing Requirements

C.9 Performance Testing [326 IAC 3-6]

- (a) Compliance testing on new emissions units shall be conducted within 60 days after achieving maximum production rate, but no later than 180 days after initial start-up, if specified in Section D of this approval. All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this permit, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ.

A test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

no later than thirty-five (35) days prior to the intended test date. The Permittee shall submit a notice of the actual test date to the above address so that it is received at least two weeks prior to the test date.

- (b) All test reports must be received by IDEM, OAQ within forty-five (45) days after the completion of the testing. An extension may be granted by the IDEM, OAQ, if the source submits to IDEM, OAQ, a reasonable written explanation within five (5) days prior to the end of the initial forty-five (45) day period.

The documentation submitted by the Permittee does not require certification by the "authorized individual" as defined by 326 IAC 2-1.1-1.

Compliance Monitoring Requirements

C.10 Compliance Monitoring [326 IAC 2-1.1-11]

Compliance with applicable requirements shall be documented as required by this permit. The Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. All monitoring and record keeping requirements not already legally required shall be implemented when operation begins.

C.11 Monitoring Methods [326 IAC 3]

Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60, Appendix A, or other approved methods as specified in this permit.

C.12 Compliance Response Plan - Preparation, Implementation, Records, and Reports [326 IAC 1-6]

- (a) The Permittee is required to prepare a Compliance Response Plan (CRP) for each compliance monitoring condition of this permit. A CRP shall be submitted to IDEM, OAQ upon request. The CRP shall be prepared within ninety (90) days after issuance of this permit by the Permittee, supplemented from time to time by the Permittee, maintain on site, and comprised of:
- (1) Reasonable response steps that may be implemented in the event that a response step is needed pursuant to the requirements of Section D of this permit; and an expected timeframe for taking reasonable response steps.
 - (2) If, at anytime, the Permittee takes reasonable response steps that are not set forth in the Permittee's current Compliance Response Plan and the Permittee documents such response in accordance with subsection (e) below, the Permittee shall amend its Compliance Response Plan to include such response steps taken.
- (b) For each compliance monitoring condition of this permit, appropriate response steps shall be taken when indicated by the provisions of that compliance monitoring condition as follows:
- (1) Reasonable response steps shall be taken as set forth in the Permittee's current Compliance Response Plan; or
 - (2) If none of the reasonable response steps listed in the Compliance Response Plan is applicable or responsive to the excursion, the Permittee shall devise and implement additional response steps as expeditiously as practical. Taking such additional response steps shall not be considered a deviation from this permit so long as the Permittee documents such response steps in accordance with this condition.
 - (3) If the Permittee determines that additional response steps would necessitate that the emissions unit or control device be shut down, the IDEM, OAQ shall be promptly notified of the expected date of the shut down, the status of the applicable compliance monitoring parameter with respect to normal, and the results of the actions taken up to the time of notification.
 - (4) Failure to take reasonable response steps shall constitute a violation of the permit.
- (c) The Permittee is not required to take any further response steps for any of the following reasons:
- (1) A false reading occurs due to the malfunction of the monitoring equipment and prompt action was taken to correct the monitoring equipment.
 - (2) The Permittee has determined that the compliance monitoring parameters established in the permit conditions are technically inappropriate, has previously submitted a request for an administrative amendment to the permit, and such request has not been denied.
 - (3) An automatic measurement was taken when the process was not operating.

- (4) The process has already returned to operating within “normal” parameters and no response steps are required.
- (d) The Permittee shall record all instances when response steps are taken.
- (e) Except as otherwise provided by a rule or provided specifically in Section D, all monitoring as required in Section D shall be performed when the emission unit is operating, except for time necessary to perform quality assurance and maintenance activities.

C.13 Actions Related to Noncompliance Demonstrated by a Stack Test

- (a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall take appropriate corrective actions. The Permittee shall submit a description of these corrective actions to IDEM, OAQ, within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize excess emissions from the affected facility while the response actions are being implemented.
- (b) A retest to demonstrate compliance shall be performed within one hundred twenty (120) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ that retesting in one-hundred and twenty (120) days is not practicable, IDEM, OAQ may extend the retesting deadline.
- (c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

The documents submitted pursuant to this condition do require the certification by the “authorized individual” as defined by 326 IAC 2-1.1-1.

Record Keeping and Reporting Requirements

C.14 Malfunctions Report [326 IAC 1-6-2]

Pursuant to 326 IAC 1-6-2 (Records; Notice of Malfunction):

- (a) A record of all malfunctions, including startups or shutdowns of any facility or emission control equipment, which result in violations of applicable air pollution control regulations or applicable emission limitations shall be kept and retained for a period of three (3) years and shall be made available to the Indiana Department of Environmental Management (IDEM), Office of Air Quality(OAQ) or appointed representative upon request.
- (b) When a malfunction of any facility or emission control equipment occurs which lasts more than one (1) hour, said condition shall be reported to OAQ, using the Malfunction Report Forms (2 pages). Notification shall be made by telephone or facsimile, as soon as practicable, but in no event later than four (4) daytime business hours after the beginning of said occurrence.
- (c) Failure to report a malfunction of any emission control equipment shall constitute a violation of 326 IAC 1-6, and any other applicable rules. Information of the scope and expected duration of the malfunction shall be provided, including the items specified in 326 IAC 1-6-2(a)(1) through (6).
- (d) Malfunction is defined as any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner. [326 IAC 1-2-39]

C.15 Monitoring Data Availability [326 IAC 2-6.1-2] [IC 13-14-1-13]

- (a) With the exception of performance tests conducted in accordance with Section C-Performance Testing, all observations, sampling, maintenance procedures, and record keeping, required as a condition of this permit shall be performed at all times the equipment is operating at normal representative conditions.
- (b) As an alternative to the observations, sampling, maintenance procedures, and record keeping of subsection (a) above, when the equipment listed in Section D of this permit is not operating, the Permittee shall either record the fact that the equipment is shut down or perform the observations, sampling, maintenance procedures, and record keeping that would otherwise be required by this permit.
- (c) If the equipment is operating but abnormal conditions prevail, additional observations and sampling should be taken with a record made of the nature of the abnormality.
- (d) If for reasons beyond its control, the operator fails to make required observations, sampling, maintenance procedures, or record keeping, reasons for this must be recorded.
- (e) At its discretion, IDEM may excuse such failure providing adequate justification is documented and such failures do not exceed five percent (5%) of the operating time in any quarter.
- (f) Temporary, unscheduled unavailability of staff qualified to perform the required observations, sampling, maintenance procedures, or record keeping shall be considered a valid reason for failure to perform the requirements stated in (a) above.

C.16 General Record Keeping Requirements [326 IAC 2-6.1-2]

- (a) Records of all required monitoring data and support information shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. These records shall be kept at the source location for a minimum of three (3) years and available upon the request of an IDEM, OAQ, representative. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a written request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.
- (b) Records of required monitoring information shall include, where applicable:
 - (1) The date, place, and time of sampling or measurements;
 - (2) The dates analyses were performed;
 - (3) The company or entity performing the analyses;
 - (4) The analytic techniques or methods used;
 - (5) The results of such analyses; and
 - (6) The operating conditions existing at the time of sampling or measurement.
- (c) Support information shall include, where applicable:
 - (1) Copies of all reports required by this permit;
 - (2) All original strip chart recordings for continuous monitoring instrumentation;

- (3) All calibration and maintenance records;
- (4) Records of preventive maintenance shall be sufficient to demonstrate that failure to implement the Preventive Maintenance Plan did not cause or contribute to a violation of any limitation on emissions or potential to emit. To be relied upon subsequent to any such violation, these records may include, but are not limited to: work orders, parts inventories, and operator's standard operating procedures. Records of response steps taken shall indicate whether the response steps were performed in accordance with the Compliance Response Plan required by Section C - Compliance Monitoring Plan - Failure to take Response Steps, of this permit, and whether a deviation from a permit condition was reported. All records shall briefly describe what maintenance and response steps were taken and indicate who performed the tasks.
- (d) All record keeping requirements not already legally required shall be implemented when operation begins.

C.17 General Reporting Requirements [326 IAC 2-1.1-11] [326 IAC 2-6.1-2] [IC 13-14-1-13]

- (a) Reports required by conditions in Section D of this permit shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

- (b) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ, on or before the date it is due.
- (c) The first report shall cover the period commencing on the date of issuance of this permit and ending on the last day of the reporting period.

C.18 Annual Notification [326 IAC 2-6.1-5(a)(5)]

- (a) Annual notification shall be submitted to the Office of Air Quality stating whether or not the source is in operation and in compliance with the terms and conditions contained in this permit.
- (b) Noncompliance with any condition must be specifically identified. If there are any permit conditions or requirements for which the source is not in compliance at any time during the year, the Permittee must provide a narrative description of how the source did or will achieve compliance and the date compliance was, or will be, achieved. The notification must be signed by an authorized individual.
- (c) The annual notice shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted in the format attached no later than March 1 of each year to:

Compliance Branch, Office of Air Quality
Indiana Department of Environmental Management
100 North Senate Avenue, P.O. Box 6015
Indianapolis, IN 46206-6015

- (d) The notification shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or

before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ, on or before the date it is due.

SECTION D.1

EMISSIONS UNIT OPERATION CONDITIONS

Facility Description:

- (a) One (1) natural gas-fired utility boiler (identified as Boiler No. 1), having a maximum heat input capacity of 2.5 MMBtu per hour and exhausting at stack S/V-01. This boiler was constructed in 1964 and uses No. 2 fuel oil as an alternative fuel.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.1.1 Particulate Matter Limitation (PM) [326 IAC 6-2-3]

Pursuant to 326 IAC 6-2-3 (d) (Particulate emission limitations for sources of indirect heating: emission limitations for facilities specified in 326 IAC 6-2-1 (b)), particulate emissions from Boiler No.1, which was existing and in operation before June 8, 1972, shall in no case exceed 0.8 pounds of particulate matter per million British thermal units heat input.

Compliance Monitoring Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.1.2 Visible Emissions Notations

- (a) Visible emission notations of the boiler stack exhaust (identified as S/V-01) shall be performed once per shift during normal daylight operations when burning fuel oil. A trained employee shall record whether emissions are normal or abnormal.
- (b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.
- (c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.
- (d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.
- (e) The Compliance Response Plan for this unit shall contain troubleshooting contingency and response steps for when an abnormal emission is observed.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.1.3 Record Keeping Requirements

- (a) To document compliance with Condition D.1.3, the Permittee shall maintain records of visible emission notations of the boiler stack exhaust (S/V-01) once per shift during normal daylight operations when burning fuel oil.
- (b) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

SECTION D.2

EMISSIONS UNIT OPERATION CONDITIONS

Facility Description:

- (b) Two (2) natural gas-fired utility boilers (identified as Boiler No. 2 and Boiler No. 3), each having a maximum heat input capacity of 14.6 MMBtu per hour. Boiler No. 2 exhausts at stack S/V-02 and Boiler No. 3 exhausts at stack S/V-03. Both boilers were constructed in 1994 and use No. 2 fuel oil as an alternative fuel.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.2.1 Particulate Matter Limitation (PM) [326 IAC 6-2-3]

Pursuant to 326 IAC 6-2-4 (Emission Limitations for facilities specified in 326 IAC 6-2-1(d)), particulate matter emissions from Boiler No.2 and Boiler No.3, which were constructed after September 21, 1983, shall be limited to 0.44 pounds per MMBtu heat input.

This limitation was calculated using the following equation:

$$P_t = \frac{1.09}{Q^{0.26}}$$

where

Pt = Pounds of particulate matter emitted per million Btu heat input
Q = Total source maximum operating capacity in MMBtu per hour
(Includes boilers 1 through 3 for a total capacity of 31.7 MMBtu/hour)

D.2.2 General Provision Relating to NSPS [326 IAC 12-1] [40 CFR 60, Subpart A]

The provisions of 40 CFR 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR 60, Subpart Dc.

D.2.3 Sulfur Dioxide (SO₂) [326 IAC 12-1] [326 IAC 7-1.1-1]

Pursuant to (SO₂ Emissions Limitations) and 40 CFR 60, Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units):

- (a) The SO₂ emissions from the thirteen (13) MMBtu per hour oil-fueled boiler shall not exceed five tenths (0.5) pounds per million Btu heat input; or
- (b) The sulfur content of the fuel oil shall not exceed five-tenths percent (0.5%) by weight. [40 CFR 60.42c(d)]

Pursuant to 40 CFR 60 Subpart Dc, the fuel oil sulfur content limit applies at all times, including periods of startup, shutdown, and malfunction.

D.2.4 Preventive Maintenance Plan

A Preventive Maintenance Plan, in accordance with Section C - Preventive Maintenance Plan, of this permit, is required for this emissions unit and its control device.

Compliance Determination Requirements

D.2.5 Testing Requirements [326 IAC 2-1.1-11]

The Permittee is not required to test this emissions unit by this permit. However, IDEM may require compliance testing when necessary to determine if the emissions unit is in compliance. If testing is required by IDEM, compliance with the PM limit specified in Condition D.1.1 shall be determined by a performance test conducted in accordance with Section C - Performance Testing.

D.2.6 Sulfur Dioxide Emissions and Sulfur Content

Pursuant to 40 CFR 60, Subpart Dc, the Permittee shall demonstrate compliance utilizing one of the following options:

- (a) Providing vendor analysis of fuel delivered, if accompanied by a certification; or
- (b) Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR 60, Appendix A, Method 19.
 - (1) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and
 - (2) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling.

Compliance Monitoring Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.2.7 Visible Emissions Notations

- (a) Visible emission notations of the boiler stack exhausts (identified as S/V-02 and S/V-03) shall be performed once per shift during normal daylight operations when burning fuel oil. A trained employee shall record whether emissions are normal or abnormal.
- (b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.
- (c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.
- (d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.
- (e) The Compliance Response Plan for this unit shall contain troubleshooting contingency and response steps for when an abnormal emission is observed.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.2.8 Record Keeping Requirements

- (a) To document compliance with Condition D.2.3, the Permittee shall maintain records in accordance with (1) through (6) below. Note that pursuant to 40 CFR 60 Subpart Dc, the fuel oil sulfur limit applies at all times including periods of startup, shutdown, and malfunction.
 - (1) Calendar dates covered in the compliance determination period;
 - (2) Actual fuel oil usage since last compliance determination period and equivalent sulfur dioxide emissions;

- (3) A certification, signed by the owner or operator, that the records of the fuel supplier certifications represent all of the fuel combusted during the period; and

If the fuel supplier certification is used to demonstrate compliance the following, as a minimum, shall be maintained:

- (4) Fuel supplier certifications;
- (5) The name of the fuel supplier; and
- (6) A statement from the fuel supplier that certifies the sulfur content of the fuel oil.

The Permittee shall retain records of all recording/monitoring data and support information for a period of five (5) years, or longer if specified elsewhere in this permit, from the date of the monitoring sample, measurement, or report. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

- (b) To document compliance with Condition D.2.7, the Permittee shall maintain records of visible emission notations of the boiler stack exhausts (S/V-02 and S/V-03) once per shift during normal daylight operations when burning fuel oil.
- (c) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

D.2.9 Reporting Requirements

A quarterly summary of the information to document compliance with Condition D.2.3 in any compliance period when No. 2 fuel oil was combusted, and the natural gas fired boiler certification, shall be submitted to the address listed in Section C - General Reporting Requirements, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported.

SECTION D.3

EMISSIONS UNIT OPERATION CONDITIONS

Facility Description:

- (c) One (1) natural gas-fired utility boiler (identified as Boiler No. 4), having a maximum heat input capacity of 3.0 MMBtu per hour and exhausting at stack S/V-04. This boiler uses No. 2 fuel oil as an alternative fuel.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.3.1 Particulate Matter Limitation (PM) [326 IAC 6-2-3]

Pursuant to 326 IAC 6-2-4 (Emission Limitations for facilities specified in 326 IAC 6-2-1(d)), particulate matter emissions from Boiler No.4, which was constructed after September 21, 1983, shall be limited to 0.43 pounds per MMBtu heat input.

This limitation was calculated using the following equation:

$$P_t = \frac{1.09}{Q^{0.26}}$$

where Pt = Pounds of particulate matter emitted per million Btu heat input
 Q = Total source maximum operating capacity in MMBtu per hour
 (Includes boilers 1 through 4 for a total capacity of 34.7 MMBtu/hour)

Compliance Monitoring Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.3.2 Visible Emissions Notations

- (a) Visible emission notations of the boiler stack exhaust (identified as S/V-04) shall be performed once per shift during normal daylight operations when burning fuel oil. A trained employee shall record whether emissions are normal or abnormal.
- (b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.
- (c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.
- (d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.
- (e) The Compliance Response Plan for this unit shall contain troubleshooting contingency and response steps for when an abnormal emission is observed.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.3.3 Record Keeping Requirements

- (a) To document compliance with Condition D.3.2, the Permittee shall maintain records of visible emission notations of the boiler stack exhaust (S/V-04) once per shift during normal daylight operations when burning fuel oil.

- (b) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

SECTION D.4

EMISSIONS UNIT OPERATION CONDITIONS

Facility Description:

- (d) Two (2) fuel oil storage tanks, constructed in 1998, each with a maximum storage capacity of 20,000 gallons. Both tanks are used to store No. 2 fuel oil exclusively.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.4.1 Volatile Organic Compound Storage Vessels [40 CFR 60, Subpart Kb]

- (a) The fuel storage tanks are subject to 40 CFR 60, Subpart Kb because the maximum capacity of each tank is greater than 40m³, each tank is used to store volatile organic liquids (including petroleum), and construction, reconstruction, or modification commenced after July 23, 1984.

Pursuant to 40 CFR 60.116(b) paragraphs (a) and (b), the Permittee shall maintain records as stated in Condition D.4.2.

- (b) The tanks are exempt from the General Provisions (Part 60, Subpart A) and from all other provisions of this subpart because each storage tank has a capacity greater than 75m³ but less than 151m³, storing liquid with a maximum true vapor pressure less than 15.0 kPa.

D.4.2 General Provision Relating to NSPS [326 IAC 12-1][40 CFR 60, Subpart A]

The provisions of 40 CFR 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR 60, Subpart Kb.

Record Keeping and Reporting Requirement [326 IAC 2-8-4(3)] [326 IAC 2-8-16]

D.4.3 Record Keeping Requirements

Pursuant to 40 CFR 60, Subpart Kb (326 IAC 12), the Permittee shall maintain annual records in accordance with (1) through (4) below:

- (1) The type of material stored in each tank;
- (2) The period of storage;
- (3) The maximum true vapor pressure of the material stored; and
- (4) The dimensions of the storage tanks and an analysis showing the capacity of the storage tanks.

Records may include Material Safety Data Sheets (MSDSs), invoices, and/or purchase orders.

The Permittee shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range. (Available data on the storage temperature may be used to determine the maximum vapor pressure as indicated in 40 CFR 60.117(b)(e)(1) through (3)).

SECTION D.5

EMISSIONS UNIT OPERATION CONDITIONS

Facility Description:

- (e) Two (2) diesel powered emergency generators each having a maximum operating capacity of 1,482 Horsepower and operating for not more than 500 hours per year.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.5.1 Limitation on Operating Hours

Operation of each emergency generator shall in no case exceed 500 hours of operation per twelve (12) consecutive month period. Any changes to the source that would require operating either emergency generator for more than 500 hours per year requires prior approval from IDEM, OAQ.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.5.2 Record Keeping Requirements

- (a) To document compliance with Condition D.5.1, the Permittee shall maintain records of the dates of operation and the number of hours of operation for each generator.

The Permittee shall retain records of all data and support information for a period of five (5) years, or longer if specified elsewhere in this permit, from the date of the monitoring sample, measurement, or report.

- (b) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION**

MSOP Quarterly Report

Source Name: Fayette Memorial Hospital
Source Address: 1941 Virginia Avenue, Connersville, Indiana 47331
MSOP No.: 041-14812-00018
Facility: Boiler No. 2 and Boiler No. 3
Parameter: Sulfur Dioxide Emissions
Limits: Sulfur content shall be less than or equal to 0.5 % by weight.

Month: _____ Year: _____

Month	Sulfur Content (%)	Heat Content	Fuel usage (gal/month)	SO ₂ Emissions (lb/MMBTU)

9 No deviation occurred in this month.

9 Deviation/s occurred in this month.
Deviation has been reported on: _____

Submitted by: _____

Title/Position: _____

Signature: _____

Date: _____

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE BRANCH**

**MINOR SOURCE OPERATING PERMIT
ANNUAL NOTIFICATION**

This form should be used to comply with the notification requirements under
326 IAC 2-6.1-5(a)(5).

Company Name:	Fayette Memorial Hospital
Address:	1941 Virginia Avenue, Connersville, Indiana 47331
City:	1941 Virginia Avenue, Connersville, Indiana 47331
Phone #:	765-825-5131
MSOP #:	041-14812-00018

I hereby certify that Fayette Memorial Hospital is

☒ still in operation.

☐ no longer in operation.

I hereby certify that Fayette Memorial Hospital is

☒ in compliance with the requirements of MSOP
041-14812-00018.

☐ not in compliance with the requirements of
MSOP 041-14812-00018.

Authorized Individual (typed):
Title:
Signature:
Date:

If there are any conditions or requirements for which the source is not in compliance, provide a narrative description of how the source did or will achieve compliance and the date compliance was, or will be achieved.

Noncompliance:

MALFUNCTION REPORT

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT OFFICE OF AIR QUALITY FAX NUMBER - 317 233-5967

This form should only be used to report malfunctions applicable to Rule 326 IAC 1-6
and to qualify for the exemption under 326 IAC 1-6-4.

THIS FACILITY MEETS THE APPLICABILITY REQUIREMENTS BECAUSE IT HAS POTENTIAL TO EMIT 25 TONS/YEAR PARTICULATE MATTER ?_____, 25 TONS/YEAR SULFUR DIOXIDE ?_____, 25 TONS/YEAR NITROGEN OXIDES?_____, 25 TONS/YEAR VOC ?_____, 25 TONS/YEAR HYDROGEN SULFIDE ?_____, 25 TONS/YEAR TOTAL REDUCED SULFUR ?_____, 25 TONS/YEAR REDUCED SULFUR COMPOUNDS ?_____, 25 TONS/YEAR FLUORIDES ?_____, 100TONS/YEAR CARBON MONOXIDE ?_____, 10 TONS/YEAR ANY SINGLE HAZARDOUS AIR POLLUTANT ?_____, 25 TONS/YEAR ANY COMBINATION HAZARDOUS AIR POLLUTANT ?_____, 1 TON/YEAR LEAD OR LEAD COMPOUNDS MEASURED AS ELEMENTAL LEAD ?_____, OR IS A SOURCE LISTED UNDER 326 IAC 2-5.1-3(2) ?_____. EMISSIONS FROM MALFUNCTIONING CONTROL EQUIPMENT OR PROCESS EQUIPMENT CAUSED EMISSIONS IN EXCESS OF APPLICABLE LIMITATION _____.

THIS MALFUNCTION RESULTED IN A VIOLATION OF: 326 IAC _____ OR, PERMIT CONDITION # _____ AND/OR PERMIT LIMIT OF _____

THIS INCIDENT MEETS THE DEFINITION OF 'MALFUNCTION' AS LISTED ON REVERSE SIDE ? Y N

THIS MALFUNCTION IS OR WILL BE LONGER THAN THE ONE (1) HOUR REPORTING REQUIREMENT ? Y N

COMPANY: _____ PHONE NO. () _____
LOCATION: (CITY AND COUNTY) _____
PERMIT NO. _____ AFS PLANT ID: _____ AFS POINT ID: _____ INSP: _____
CONTROL/PROCESS DEVICE WHICH MALFUNCTIONED AND REASON: _____

DATE/TIME MALFUNCTION STARTED: ____/____/20____ AM / PM

ESTIMATED HOURS OF OPERATION WITH MALFUNCTION CONDITION:

DATE/TIME CONTROL EQUIPMENT BACK-IN SERVICE ____/____/20____ AM/PM

TYPE OF POLLUTANTS EMITTED: TSP, PM-10, SO₂, VOC, OTHER: _____

ESTIMATED AMOUNT OF POLLUTANT EMITTED DURING MALFUNCTION: _____

MEASURES TAKEN TO MINIMIZE EMISSIONS: _____

REASONS WHY FACILITY CANNOT BE SHUTDOWN DURING REPAIRS:

CONTINUED OPERATION REQUIRED TO PROVIDE ESSENTIAL* SERVICES: _____

CONTINUED OPERATION NECESSARY TO PREVENT INJURY TO PERSONS: _____

CONTINUED OPERATION NECESSARY TO PREVENT SEVERE DAMAGE TO EQUIPMENT: _____

INTERIM CONTROL MEASURES: (IF APPLICABLE) _____

MALFUNCTION REPORTED BY: _____ TITLE: _____
(SIGNATURE IF FAXED)

MALFUNCTION RECORDED BY: _____ DATE: _____ TIME: _____

*SEE PAGE 2

**Please note - This form should only be used to report malfunctions
applicable to Rule 326 IAC 1-6 and to qualify for
the exemption under 326 IAC 1-6-4.**

326 IAC 1-6-1 Applicability of rule

Sec. 1. This rule applies to the owner or operator of any facility required to obtain a permit under 326 IAC 2-5.1 or 326 IAC 2-6.1.

326 IAC 1-2-39 "Malfunction" definition

Sec. 39. Any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner.

***Essential services** are interpreted to mean those operations, such as, the providing of electricity by power plants. Continued operation solely for the economic benefit of the owner or operator shall not be sufficient reason why a facility cannot be shutdown during a control equipment shutdown.

If this item is checked on the front, please explain rationale:

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION**

**MINOR SOURCE OPERATING PERMIT (MSOP)
NATURAL GAS FIRED BOILER CERTIFICATION**

Source Name: Fayette Memorial Hospital
Source Address: 1941 Virginia Avenue, Connersville, Indiana 47331
Mailing Address: 1941 Virginia Avenue, Connersville, Indiana 47331
MSOP No.: 041-14812-00018

9	Natural Gas Only
9	Alternate Fuel burned
From: _____	To: _____

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:

Printed Name:

Title/Position:

Date:

A certification by the responsible official as defined by 326 IAC 2-6.1-6 (d) is required for this report.

Indiana Department of Environmental Management Office of Air Quality

Addendum to the Technical Support Document for a Minor Source Operating Permit (MSOP)

Source Background and Description

Source Name: Fayette Memorial Hospital
Source Location: 1941 Virginia Avenue, Connersville, Indiana 47331
County: Fayette
SIC Code: 8062
Operation Permit No.: F041-14812-00018
Permit Reviewer: ERG/AB

On January, the Office of Air Quality (OAQ) had a notice published in the News Examiner, Connersville, Indiana, stating that Fayette Memorial Hospital had applied for a Minor Source Operating Permit (MSOP) to operate to construct and operate utility boilers, storage tanks, and an emergency generator. The notice also stated that OAQ proposed to issue a permit for this operation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

Upon further review, the OAQ has decided to make the following revisions to the permit (bolded language has been added, the language with a line through it has been deleted). The table of contents has been revised as appropriate.

The IDEM, OAQ has restructured C.12 to clarify the contents and implementation of the compliance response plan. The language regarding the OAQ's discretion to excuse failure to perform monitoring under certain conditions has been deleted. The OAQ retains this discretion to excuse minor incidents of missing data; however, it is not necessary to state criteria regarding the exercise of that discretion in the permit. The title Compliance Monitoring Plan - Failure to Take Response Steps has been changed to Compliance Response Plan - Preparation, Implementation, Records, and Reports throughout the permit.

C.12 Compliance ~~Monitoring Response~~ Plan - Failure to Take Response Steps **Preparation, Implementation, Records, and Reports** [326 IAC 1-6]

-
- (a) The Permittee is required to **prepare** ~~implement: a compliance monitoring plan to ensure that reasonable information is available to evaluate its continuous compliance with applicable requirements. The compliance monitoring plan is comprised~~
- (1) ~~This condition;~~
- (2) ~~The Compliance Determination Requirements in Section D of this permit;~~
- (3) ~~The Compliance Monitoring Requirements in Section D of this permit;~~
- (4) ~~The Record Keeping and Reporting Requirements in Section C (Monitoring Data Availability, General Record Keeping Requirements, and General Reporting Requirements) and in Section D of this permit; and~~

- (5) ~~A~~ **a Compliance Response Plan (CRP) for each compliance monitoring condition of this permit. A CRP's shall be submitted to IDEM, OAQ upon request and shall be subject to review and approval by IDEM, OAQ. The CRP shall be prepared within ninety (90) days after issuance of this permit by the Permittee, supplemented from time to time by the Permittee, and maintained on site, and is comprised of:**
- (A)(1) **Reasonable** response steps that may be implemented in the event that ~~compliance-related information indicates that~~ a response step is needed pursuant to the requirements of Section D of this permit; and **an expected timeframe for taking reasonable response steps.**
- (B) ~~A time schedule for taking such response steps including a schedule for devising additional response steps for situations that may not have been predicted.~~
- (2) **If, at any time, the Permittee takes reasonable response steps that are not set forth in the Permittee's current Compliance Response Plan and the Permittee documents such response in accordance with subsection (e) below, the Permittee shall amend its Compliance Response Plan to include such response steps taken.**
- (b) For each compliance monitoring condition of this permit, ~~reasonable~~ appropriate response steps shall be taken when indicated by the provisions of that compliance monitoring condition **as follows:** ~~Failure to perform the actions detailed in the compliance monitoring condition or failure take the response steps within the time prescribed in the Compliance Response Plan, shall constitute a violation of the permit unless taking the response steps set forth in the Compliance Response Plan would unreasonable.~~
- (1) **Reasonable response steps shall be taken as set forth in the Permittee's current Compliance Response Plan; or**
- (2) **If none of the reasonable response steps listed in the Compliance Response Plan is applicable or responsive to the excursion, the Permittee shall devise and implement additional response steps as expeditiously as practical. Taking such additional response steps shall not be considered a deviation from this permit so long as the Permittee documents such response steps in accordance with this condition.**
- (3) **If the Permittee determines that additional response steps would necessitate that the emissions unit or control device be shut down, the IDEM, OAQ shall be promptly notified of the expected date of the shut down, the status of the applicable compliance monitoring parameter with respect to normal, and the results of the actions taken up to the time of notification.**
- (4) **Failure to take reasonable response steps shall constitute a violation of the permit.**
- (c) ~~After investigating the reason for the excursion, the~~ **The Permittee is excused from taking not required to take any** further response steps for any of the following reasons:

- (1) ~~The monitoring equipment malfunctioned, giving a false reading.~~ **A false reading occurs due to the malfunction of the monitoring equipment and This shall be an excuse from taking further response steps providing that prompt action was taken to correct the monitoring equipment.**
 - (2) The Permittee has determined that the compliance monitoring parameters established in the permit conditions are technically inappropriate, has previously submitted a request for an administrative amendment to the permit, and such request has not been denied; or
 - (3) An automatic measurement was taken when the process was not operating; or
 - (4) The process has already returned **or is returning** to operating within "normal" parameters and no response steps are required.
- (d) ~~Records shall be kept of all instances in which the compliance related information was not met and of all response steps taken.~~ **The Permittee shall record all instances when response steps are taken.**
- (e) **Except as otherwise provided by a rule or provided specifically in Section D, all monitoring as required in Section D shall be performed when the emission unit is operating, except for time necessary to perform quality assurance and maintenance activities.**

Indiana Department of Environmental Management Office of Air Quality

Technical Support Document (TSD) for a Minor Source Operating Permit

Source Background and Description

Source Name: Fayette Memorial Hospital
Source Location: 1941 Virginia Avenue, Connersville, Indiana 47331
County: Fayette
SIC Code: 8062
Operation Permit No.: 041-14812-00018
Permit Reviewer: ERG/AB

The Office of Air Quality (OAQ) has reviewed an application from Fayette Memorial Hospital relating to the construction and operation of four boilers, two fuel oil storage tanks, and one diesel powered emergency generator.

Unpermitted Emission Units and Pollution Control Equipment

The source consists of the following unpermitted facilities/units:

- (a) One (1) natural gas-fired utility boiler (identified as Boiler No. 1), having a maximum heat input capacity of 2.5 MMBtu per hour and exhausting at stack S/V-01. This boiler was constructed in 1964 and uses No. 2 fuel oil as an alternative fuel.
- (b) Two (2) natural gas-fired utility boilers (identified as Boiler No. 2 and Boiler No. 3), each having a maximum heat input capacity of 14.6 MMBtu per hour. Boiler No. 2 exhausts at stack S/V-02 and Boiler No. 3 exhausts at stack S/V-03. Both boilers were constructed in 1994 and use No. 2 fuel oil as an alternative fuel.
- (c) Two (2) fuel oil storage tanks, constructed in 1998, each with a maximum storage capacity of 20,000 gallons. Both tanks are used to store No. 2 fuel oil exclusively.

New Emission Units and Pollution Control Equipment Receiving Prior Approval

The following new construction activities are included in this permit:

- (d) Two (2) diesel powered emergency generators, each having a maximum operating capacity of 1,482 horsepower and operating for not more than 500 hours per year.

Note: The two new generators will replace the existing permitted 1,482 horsepower generator.

- (e) One (1) natural gas-fired utility boiler (identified as Boiler No. 4), having a maximum heat input capacity of 3.0 MMBtu per hour and exhausting at stack S/V-04. This boiler uses No. 2 fuel oil as an alternative fuel.

Existing Approvals

Their were no previous approvals issued to this source.

Enforcement Issue

- (a) IDEM is aware that equipment has been constructed and prior to receipt of the proper permit. The subject equipment is listed in this Technical Support Document under the condition titled *Unpermitted Emission Units and Pollution Control Equipment*.
- (b) IDEM is reviewing this matter and will take appropriate action. This proposed permit is intended to satisfy the requirements of the construction permit rules.

Stack Summary

Stack ID	Operation	Height (feet)	Diameter (feet)	Flow Rate (acfm)	Temperature (°F)
S/V-01	Boiler No. 1	45.5	0.83	2,200	350
S/V-02	Boiler No. 2	45.0	1.67	4,400	350
S/V-03	Boiler No. 3	45.0	1.67	4,400	350
S/V-04	Boiler No. 4	45.0	1.0	600	350

Recommendation

The staff recommends to the Commissioner that the construction and operation be approved. This recommendation is based on the following facts and conditions:

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant.

A complete application for the purposes of this review was received on August 30, 2001.

Emission Calculations

See Appendix A of this document for detailed emissions calculations (pages 1 through 5).

Potential To Emit of Source Before Controls

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as “the maximum capacity of a stationary source or emissions unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, the department, or the appropriate local air pollution control agency.”

Pollutant	Potential To Emit (tons/year)
PM	2.72
PM-10	2.72
SO ₂	80.1
VOC	1.32
CO	16.8
NO _x	39.5

Note: The PTE for the emergency generator was calculated at a maximum of 500 hours of operation per twelve (12) consecutive month period.

- (a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of pollutants are less than 100 tons per year. Therefore, the source is not subject to the provisions of 326 IAC 2-7.
- (b) The potential to emit (as defined in 326 IAC 2-7-1(29)) of pollutants are greater than 25 tons per year, therefore, the source is subject to the provisions of 326 IAC 2-6.1.
- (c) The potential to emit (as defined in 326 IAC 2-7-1(29)) of any single HAP is less than ten (10) tons per year and/or the potential to emit (as defined in 326 IAC 2-7-1(29)) of a combination of HAPs is less than twenty-five (25) tons per year, therefore, the source is not subject to the provisions of 326 IAC 2-7.
- (d) **Fugitive Emissions**
Since this type of operation is not one of the twenty-eight (28) listed source categories under 326 IAC 2-2 and since there are no applicable New Source Performance Standards that were in effect on August 7, 1980, the fugitive particulate matter (PM) and volatile organic compound (VOC) emissions are not counted toward determination of PSD and Emission Offset applicability.

County Attainment Status

The source is located in Fayette County.

Pollutant	Status
PM-10	Attainment
SO ₂	Attainment
NO ₂	Attainment
Ozone	Attainment
CO	Attainment
Lead	Attainment

- (a) Volatile organic compounds (VOC) are precursors for the formation of ozone. Therefore, VOC emissions are considered when evaluating the rule applicability relating to the ozone standards. Fayette County has been designated as attainment or unclassifiable for ozone. Therefore, VOC emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.
- (b) Fayette County has been classified as attainment or unclassifiable for PM₁₀, SO₂, NO₂, CO and lead. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.
- (c) **Fugitive Emissions**
Since this type of operation is not one of the 28 listed source categories under 326 IAC 2-2, 40 CFR 52.21, or 326 IAC 2-3 and since there are no applicable New Source Performance Standards that were in effect on August 7, 1980, the fugitive particulate matter (PM) and volatile organic compound (VOC) emissions are not counted toward determination of PSD and Emission Offset applicability.

Source Status

New Source PSD Definition (emissions after controls, based on 8,760 hours of operation per year at rated capacity and/ or as otherwise limited):

Pollutant	Emissions (ton/yr)
PM	2.72
PM10	2.72
SO ₂	80.1
VOC	1.32
CO	16.8
NO _x	39.5

- (a) This new source is **not** a major stationary source because no attainment regulated pollutant is emitted at a rate of 250 tons per year or more, and it is not in one of the 28 listed source categories.

Part 70 Permit Determination

326 IAC 2-7 (Part 70 Permit Program)

This new source is not subject to the Part 70 Permit requirements because the potential to emit (PTE) of:

- (a) each criteria pollutant is less than 100 tons per year,
- (b) a single hazardous air pollutant (HAP) is less than 10 tons per year, and
- (c) any combination of HAPs is less than 25 tons/year.

This is the first permit issued to this source.

Federal Rule Applicability

- (a) Boilers 2 and 3 are subject to the New Source Performance Standard, 40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (326 IAC 12) because the boilers were constructed after June 9, 1989 and have maximum heat input capacities greater than 10 MMBtu/hr and less than 100 MMBtu/hr.

Pursuant to 40 CFR 60, Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units), the sulfur content of the fuel oil burned in each of these boilers shall not exceed five-tenths percent (0.5%) by weight [40 CFR 60.42c(d)]. This fuel oil sulfur content limit applies at all times, including periods of startup, shutdown, and malfunction.

- (b) Boilers 1 and 4 are not subject to the New Source Performance Standard, 40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (326 IAC 12) because:

- (1) Boiler 1 has a heat input less than 10 MMBtu per hour, was constructed in 1964 and has not been modified or reconstructed since June 9, 1989.
- (2) Boiler 4 has a heat input less than 10 MMBtu per hour.

- (c) This source is subject to the New Source Performance Standard (NSPS), 40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (326 IAC 12), because the storage tanks located at this source have capacities greater than 40 cubic meters (10,567 gallons), they are used to store petroleum liquids, and they were constructed in 1998. Although the storage tanks each have a storage capacity above 75 cubic meters (19,812 gallons), the

maximum true vapor pressure for the fuel oil stored in the tanks is less than 15.0 Kpa. Consequently, this storage tank is subject only to the record keeping provisions in 40 CFR 60.116b, paragraphs (a) and (b).

- (d) This source is not subject to the provisions of the New Source Performance Standard (NSPS), 40 CFR 60, Subpart Ec - Standards of Performance for Hospital/Medical/Infectious Waste Incinerators for which construction is commenced after June 20, 1996 (326 IAC 14) because this source does not operate an incinerator.
- (e) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs)(326 IAC 14 and 40 CFR Part 63) applicable to this source.

State Rule Applicability - Entire Source

326 IAC 2-6 (Emission Reporting)

This source is located in Fayette County and the potential to emit CO, VOC, NO_x, PM₁₀, and SO₂ is less than one hundred (100) tons per year. Therefore, 326 IAC 2-6 does not apply.

326 IAC 5-1 (Visible Emissions Limitations)

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

- (a) Opacity shall not exceed an average of forty percent (40%) any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.
- (b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings) as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

State Rule Applicability - Individual Facilities

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))

The operation of the boilers and the emergency generator will each emit less than 10 tons per year of a single HAP or 25 tons per year of a combination of HAPs. Therefore, 326 IAC 2-4.1 does not apply.

326 IAC 8-1-6 (New Facilities - General Reduction Requirement)

This source does not have potential VOC emissions equal to or greater than twenty five (25) tons per year, therefore this source is not subject to the provisions of 326 IAC 8-1-6.

326 IAC 7-1.1-1(Sulfur Dioxide Emissions)

Pursuant to 326 IAC 7-1.1 (SO₂ Emissions Limitations) the SO₂ emissions from boilers 2 and 3 shall not exceed five tenths (0.5) pounds per million Btu heat input.

326 IAC 7-1.1 (SO₂ Emissions Limitations) is not applicable to boilers 1 and 4 because they have the potential to emit sulfur dioxide of less than twenty-five (25) tons per year.

326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating)

Pursuant to 326 IAC 6-2-3 (d) (Particulate emission limitations for sources of indirect heating: emission limitations for facilities specified in 326 IAC 6-2-1 (b)), particulate emissions from boiler 1, which was existing and in operation before June 8, 1972, shall in no case exceed 0.8 pounds of particulate matter per million British thermal units heat input.

$$P_t = \frac{C \times a \times h}{76.5 \times Q^{0.75} \times N^{0.25}}$$

Where:

C = maximum ground level concentration with respect to distance from the point source at "critical" wind speed for level terrain.

P_t = pounds of particulate matter emitted per million Btu heat input (lb/MMBtu).

Q = total source operating capacity

N = number of stacks in fuel burning operation

a = 0.67 rise factor

h = stack height

$$P_t = \frac{(50) (0.67) (45.5)}{(76.5) (2.5)^{0.75} (1.0)^{0.25}}$$

$$P_t = 10.02 \text{ lb/MMBtu}$$

Since the limit calculated using the formula in 326 IAC 6-2-3(a) is greater than the limit in 326 IAC 6-2-3(d), the boiler shall comply with a PM limit of 0.8 lb per MMBtu heat input.

326 IAC 6-2-4 (Particulate Matter Emission Limitations for Sources of Indirect Heating)

Pursuant to 326 IAC 6-2-4 (Particulate Matter Emission Limitations for Sources of Indirect Heating: Emissions Limitations for Facilities Specified in 326 IAC 6-2-1(d)), the PM emissions from boilers 2 and 3 shall be limited to 0.44 pounds per MMBtu heat input.

This limitation was calculated using the following equation:

$$P_t = \frac{1.09}{Q^{0.26}}$$

Where:

P_t = Pounds of particulate matter emitted per million Btu heat input; and

Q = Total source maximum operating capacity in MMBtu per hour (includes boilers 1 through 3)

$$Q = (2) (14.6 \text{ MMBtu/hour}) + 2.5 \text{ MMBtu/hour}$$

$$Q = 31.7 \text{ MMBtu/hour}$$

$$P_t = \frac{1.09}{Q^{0.26}} = 0.44 \text{ lb/MMBtu heat input}$$

326 IAC 6-2-4 (Particulate Matter Emission Limitations for Sources of Indirect Heating)

Pursuant to 326 IAC 6-2-4 (Particulate Matter Emission Limitations for Sources of Indirect Heating: Emissions Limitations for Facilities Specified in 326 IAC 6-2-1(d)), the PM emissions from boiler 4 shall be limited to 0.43 pounds per MMBtu heat input.

This limitation was calculated using the following equation:

$$P_t = \frac{1.09}{Q^{0.26}}$$

Where:

P_t = Pounds of particulate matter emitted per million Btu heat input; and

Q = Total source maximum operating capacity in MMBtu per hour (includes boilers 1 through 4)

$$Q = (2) (14.6 \text{ MMBtu/hour}) + 2.5 \text{ MMBtu/hour} + 3.0 \text{ MMBtu/hour}$$

$$Q = 34.7 \text{ MMBtu/hour}$$

$$P_t = \frac{1.09}{Q^{0.26}} = 0.43 \text{ lb/MMBtu heat input}$$

State Rule Applicability - Emergency Generator

For the emergency generators, the potential to emit air pollutants was calculated at a maximum of 500 operating hours per year for each unit. As a result, the following condition was added to the permit to make the limit on the number of operating hours enforceable.

Operation of each emergency generator shall in no case exceed 500 hours of operation per twelve (12) consecutive month period. Any changes to the source that would require operating either emergency generator for more than 500 hours per year requires prior approval from IDEM, OAQ.

Conclusion

The construction and operation of the new utility boiler and the operation of the existing boilers and emergency generator shall be subject to the conditions of the attached proposed Minor Source Operating Permit 041-14812-00018.

Appendix A: Emissions Calculations

Natural Gas Combustion Only

MM BTU/HR <100

Small Industrial Boilers No. 1 through No. 4

Company Name: Fayette Memorial Hospital

Address City IN Zip: 1941 Virginia Ave, Connersville, Indiana

CP: 041-14812

Plt ID: 041-00018

Reviewer: ERG/AB

Date: 09/10/01

Heat Input Capacity
MMBtu/hr

Potential Throughput
MMCF/yr

34.7

304.0

Includes boilers identified as No.1 through No.4 (i.e.; two 14.6 MMBtu/hr boilers, one 2.5 MMBtu/hr boiler and one 3 MMBtu/hour boiler).

Pollutant

Emission Factor in lb/MMCF	PM*	PM10*	SO2	NOx	VOC	CO
	7.6	7.6	0.6	100.0	5.5	84.0
				**see below		
Potential Emission in tons/yr	1.2	1.2	0.1	15.2	0.8	12.8

*PM emission factor is filterable and condensable PM.

**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology

All emission factors are based on normal firing.

MMBtu = 1,000,000 Btu

MMCF = 1,000,000 Cubic Feet of Gas

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu

Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03 (SUPPLEMENT D 3/98)

Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Note: Check the applicable rules and test methods for PM and PM10 when using the above emission factors to confirm that the correct factor is used (i.e., condensable included/not included).

See page 2 for HAPs emissions calculations.

**Appendix A: Emissions Calculations
Natural Gas Combustion Only**

Page 2 of 5 TSD App A

MM BTU/HR <100

Small Industrial Boilers No. 1 through No. 4

HAPs Emissions

Company Name: Fayette Memorial Hospital

Address City IN Zip: 1941 Virginia Ave, Connersville, Indiana

CP: 041-14812

Plt ID: 041-00018

Reviewer: ERG/AB

Date: 09/10/01

HAPs - Organics

Emission Factor in lb/MMcf	Benzene 2.1E-03	Dichlorobenzene 1.2E-03	Formaldehyde 7.5E-02	Hexane 1.8E+00	Toluene 3.4E-03
Potential Emission in tons/yr	3.192E-04	1.824E-04	1.140E-02	2.736E-01	5.168E-04

HAPs - Metals

Emission Factor in lb/MMcf	Lead 5.0E-04	Cadmium 1.1E-03	Chromium 1.4E-03	Manganese 3.8E-04	Nickel 2.1E-03
Potential Emission in tons/yr	7.599E-05	1.672E-04	2.128E-04	5.775E-05	3.192E-04

Methodology is the same as page 1.

The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A: Emissions Calculations
Commercial/Institutional/Residential Combustors (< 100 mmBtu/hr)
#2 Fuel Oil

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Small Industrial Boilers No. 1 through No. 4
Company Name: Fayette Memorial Hospital
Address, City IN Zip: 1941 Virginia Ave, Connersville, Indiana
CP: 041-14812
Plt ID: 041-00018
Reviewer: ERG/AB
Date: 09/10/01

Heat Input Capacity Potential Throughput S = Weight % Sulfur
MMBtu/hr kgals/year 0.5

34.7

2171.22857

Includes boilers identified as No.1 through No.4 (i.e.; two 14.6 MMBtu/hr boilers, one 2.5 MMBtu/hr boiler and one 3 MMBtu/hour boiler).

Emission Factor in lb/kgal	Pollutant				
	PM*	SO ₂	NO _x	VOC	CO
	2.0	71 (142.0S)	20.0	0.34	5.0
Potential Emission in tons/yr	2.2	77.1	21.7	0.4	5.4

Methodology

1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu

Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu

Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, and 1.3-3 (SCC 1-03-005-01/02/03) Supplement E 9/98 (see erata file)

*PM emission factor is filterable PM only. Condensable PM emission factor is 1.3 lb/kgal.

Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton

Note: Check the applicable rules and test methods for PM and PM₁₀ when using the above emission factors to confirm that the correct factor is used (i.e., condensable included/not included).

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updated 4/99

Appendix A: Emissions Calculations
Commercial/Institutional/Residential Combustors (< 100 mmBtu/hr)

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#2 Fuel Oil

HAPs Emissions

Small Industrial Boilers No. 1 through No. 4

Company Name: Fayette Memorial Hospital
Address, City IN Zip: 1941 Virginia Ave, Connorsville, Indiana
CP: 041-14812
Pit ID: 041-00018
Reviewer: ERG/AB
Date: 09/10/01

HAPs - Metals

Emission Factor in lb/mmBtu	Arsenic 4.0E-06	Beryllium 3.0E-06	Cadmium 3.0E-06	Chromium 3.0E-06	Lead 9.0E-06
Potential Emission in tons/yr	6.08E-04	4.56E-04	4.56E-04	4.56E-04	1.37E-03

HAPs - Metals (continued)

Emission Factor in lb/mmBtu	Mercury 3.0E-06	Manganese 6.0E-06	Nickel 3.0E-06	Selenium 1.5E-05
Potential Emission in tons/yr	4.56E-04	9.12E-04	4.56E-04	2.28E-03

Methodology

No data was available in AP-42 for organic HAPs.

Potential Emissions (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*8,760 hrs/yr / 2,000 lb/ton

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updated 4/99

Appendix A: Emission Calculations
Internal Combustion Engines - Diesel Fuel
Turbine (>600 HP)

Company Name: Fayette Memorial Hospital
Address City IN Zip: 1941 Virginia Ave, Connersville, Indiana
CP#: 041-14812
Plt ID: 041-00018
Reviewer: ERG/AB
Date: 09/10/01

Emissions calculated based on output rating (hp)

Heat Input Capacity
Horsepower (hp)

Potential Throughput
hp-hr/yr

S= 0.5 = WEIGHT % SULFUR

1482.0

12982320.0

Emission Factor in lb/hp-hr	Pollutant					
	PM*	PM10*	SO2	NOx	VOC	CO
	0.0007	not provided	0.0040 (.00809S)	0.024 **see below	0.00071	0.00550
Potential Emission in tons/yr	4.5	0.0	26.3	155.8	4.6	35.7
Potential Emissions assuming 500 hours Operation per year (tons/yr)	0.26	0.00	1.50	8.89	0.26	2.04
Potential emissions for two generators(tons/yr)	0.52	0.00	3.00	17.78	0.52	4.08

**NOx emission factor: uncontrolled = 0.024 lb/hp-hr, controlled by ignition timing retard = 0.013 lb/hp-hr

Note that the PM10 emission factor in lb/hp-hr is not provided in the Supplement B update of AP-42.

An average conversion factor of 1hp-hr = 7,000Btu is provided below.

Methodology

Potential Throughput (hp-hr/yr) = hp * 8760 hr/yr

Emission Factors are from AP 42 (Supplement B 10/96)Table 3.4-1 and Table 3.4-2

1 hp-hr = 7000 Btu, AP42 (Supplement B 10/96), Table 3.3-1, Footnote a.

Emission (tons/yr) = [Heat input rate (MMBtu/hr) x Emission Factor (lb/MMBtu)] * 8760 hr/yr / (2,000 lb/ton)

Emission (tons/yr) = [Potential Throughput (hp-hr/yr) x Emission Factor (lb/hp-hr)] / (2,000 lb/ton)

Emissions (tons/yr) assuming 500 hrs operation = Emissions per year (tons/yr) * (500/8760)

*No information was given regarding which method was used to determine the PM emission factor or whether condensable PM is included. The PM10 emission factor is filterable and condensable PM10 combined.

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electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51820, 51825, Dec. 18, 1989; 60 FR 28062, May 30, 1995; 61 FR 14031, Mar. 29, 1996; 62 FR 52641, Oct. 8, 1997; 63 FR 49455, Sept. 16, 1998; 64 FR 7464, Feb. 12, 1999]

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

SOURCE: 55 FR 37683, Sept. 12, 1990, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO₂) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§ 60.42c, 60.43c, 60.44c, 60.45c,

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60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996]

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam ch a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing and Materials in ASTM D388-77, "Standard Specification for Classification of Coals by Rank" (incorporated by reference—see § 60.17); coal refuse; and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Cogeneration steam generating unit means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (i.e., the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396-78, "Standard Specification for Fuel Oils" (incorporated by reference—see § 60.17).

Dry flue gas desulfurization technology means a sulfur dioxide (SO₂) control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO₂ control system that is not defined as a conventional technology under this

section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR Parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means (1) a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835-86, "Standard Specification for Liquefied Petroleum

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Gases” (incorporated by reference—see § 60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO₂ emissions (nanograms per joule [ng/J], or pounds per million Btu [lb/million Btu] heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396–78, “Standard Specification for Fuel Oils” (incorporated by reference—see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Wet flue gas desulfurization technology means an SO₂ control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where

the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of particulate matter (PM) or SO₂.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996]

§ 60.42c Standard for sulfur dioxide.

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner the operator of an affected facility that combusts only coal shall neither: (1) cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction); nor (2) cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/million Btu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 90 percent SO₂ reduction requirement specified in this paragraph and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of

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20 percent (0.20) of the potential SO₂ emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/million Btu) heat input. If coal is fired with coal refuse, the affected facility is subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 90 percent SO₂ reduction requirement specified in paragraph (a) of this section and the emission limit determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO₂ emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 50 percent (0.50) of the potential SO₂ emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 260 ng/J (0.60 lb/million Btu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO₂ reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under this paragraph.

(1) Affected facilities that have a heat input capacity of 22 MW (75 million Btu/hr) or less.

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a Feder-

ally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area.

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 215 ng/J (0.50 lb/million Btu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the following:

(1) The percent of potential SO₂ emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel,

(ii) Has a heat input capacity greater than 22 MW (75 million Btu/hr), and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts

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coal, oil, or coal and oil with any other fuel:

$$E_s = (K_a H_a + K_b H_b + K_c H_c) / (H_a + H_b + H_c)$$

where:

E_s is the SO₂ emission limit, expressed in ng/J or lb/million Btu heat input,

K_a is 520 ng/J (1.2 lb/million Btu),

K_b is 260 ng/J (0.60 lb/million Btu),

K_c is 215 ng/J (0.50 lb/million Btu),

H_a is the heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [million Btu]

H_b is the heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (million Btu)

H_c is the heat input from the combustion of oil, in J (million Btu).

(f) Reduction in the potential SO₂ emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO₂ emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO₂ control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), or (3) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f)(1), (2), or (3), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 million Btu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 million Btu/hr).

(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 million Btu/hr).

(i) The SO₂ emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

§ 60.43c Standard for particulate matter.

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.05 lb/million Btu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in

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excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/million Btu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and in § 60.8(b), performance tests required under § 60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under § 60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO₂ emission limits under § 60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after

achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) and § 60.8, compliance with the percent reduction requirements and SO₂ emission limits under § 60.42c is based on the average percent reduction and the average SO₂ emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO₂ emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 are used to determine the hourly SO₂ emission rate (E_{ho}) and the 30-day average SO₂ emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS). Method 19 shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho} (E_{hoO}) is used in Equation 19-19 of Method 19 to compute the adjusted E_{ao} (E_{aoO}). The E_{hoO} is computed using the following formula:

$$E_{hoO} = [E_{ho} - E_w(1 - X_k)] / X_k$$

where:

E_{hoO} is the adjusted E_{ho} , ng/J (lb/million Btu)

E_{ho} is the hourly SO₂ emission rate, ng/J (lb/million Btu)

E_w is the SO₂ concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9, ng/J (lb/million Btu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w=0$.

X_k is the fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19.

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(2) The owner or operator of an affected facility that qualifies under the provisions of § 60.42c(c) or (d) [where percent reduction is not required] does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19.

(f) Affected facilities subject to the percent reduction requirements under § 60.42c(a) or (b) shall determine compliance with the SO_2 emission limits under § 60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:

$$\%P_s = 100(1 - \%R_g/100)(1 - \%R_f/100)$$

where

$\%P_s$ is the percent of potential SO_2 emission rate, in percent

$\%R_g$ is the SO_2 removal efficiency of the control device as determined by Method 19, in percent

$\%R_f$ is the SO_2 removal efficiency of fuel pretreatment as determined by Method 19, in percent

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$ ($\%R_{go}$) is computed from E_{aoO} from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate (E_{aiO}) using the following formula:

$$\%R_{go} = 100 [1.0 - E_{aoO}/E_{aiO}]$$

where:

$\%R_{go}$ is the adjusted $\%R_g$, in percent

E_{aoO} is the adjusted E_{ao} , ng/J (lb/million Btu)

E_{aiO} is the adjusted average SO_2 inlet rate, ng/J (lb/million Btu)

(ii) To compute E_{aiO} , an adjusted hourly SO_2 inlet rate (E_{hiO}) is used. The E_{hiO} is computed using the following formula:

$$E_{hiO} = [E_{hi} - E_w (1 - X_k)]/X_k$$

where:

E_{hiO} is the adjusted E_{hi} , ng/J (lb/million Btu)

E_{hi} is the hourly SO_2 inlet rate, ng/J (lb/million Btu)

E_w is the SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19, ng/J (lb/million Btu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$.

X_k is the fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under § 60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under § 60.46c(d)(2).

(h) For affected facilities subject to § 60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification, the certification from the fuel supplier, as described under § 60.48c(f)(1), (2), or (3), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under § 60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour averaged firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the

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affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO₂ emissions data in calculating %P_s and E_{ho} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under § 60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating %P_s or E_{ho} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under § 60.43c shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods.

(1) Method 1 shall be used to select the sampling site and the number of traverse sampling points. The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry square cubic meters (dscm) [60 dry square cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(2) Method 3 shall be used for gas analysis when applying Method 5, Method 5B, or Method 17.

(3) Method 5, Method 5B, or Method 17 shall be used to measure the concentration of PM as follows:

(i) Method 5 may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 2.1 and 2.3 of Method 5B may be used in Method 17 only if Method 17 is used in conjunction with a wet scrub-

ber system. Method 17 shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B may be used in conjunction with a wet scrubber system.

(4) For Method 5 or Method 5B, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 °C (320 °F).

(5) For determination of PM emissions, an oxygen or carbon dioxide measurement shall be obtained simultaneously with each run of Method 5, Method 5B, or Method 17 by traversing the duct at the same sampling location.

(6) For each run using Method 5, Method 5B, or Method 17, the emission rates expressed in ng/J (lb/million Btu) heat input shall be determined using:

(i) The oxygen or carbon dioxide measurements and PM measurements obtained under this section,

(ii) The dry basis F-factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 (appendix A).

(7) Method 9 (6-minute average of 24 observations) shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under § 60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

§ 60.46c Emission monitoring for sulfur dioxide

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or

operator of an affected facility subject to the SO₂ emission limits under § 60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO₂ concentrations and either oxygen or carbon dioxide concentrations at the outlet of the SO₂ control device (or the outlet of the steam generating unit if no SO₂ control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under § 60.42c shall measure SO₂ concentrations and either oxygen or carbon dioxide concentrations at both the inlet and outlet of the SO₂ control device.

(b) The 1-hour average SO₂ emission rates measured by a CEM shall be expressed in ng/J or lb/million Btu heat input and shall be used to calculate the average emission rates under § 60.42c. Each 1-hour average SO₂ emission rate must be based on at least 30 minutes of operation and include at least 2 data points representing two 15-minute periods. Hourly SO₂ emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 (appendix B).

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 (appendix F).

(3) For affected facilities subject to the percent reduction requirements under § 60.42c, the span value of the SO₂ CEMS at the inlet to the SO₂ control device shall be 125 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted, and the span value of the SO₂ CEMS at the outlet from the SO₂ control device shall be 50 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of § 60.42c, the span value of the SO₂ CEMS at the outlet from the

SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) shall be 125 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO₂ emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEM at the outlet from the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO₂ emission rate by using Method 6B. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19. Method 19 provides procedures for converting these measurements into the format to be used in calculating the average SO₂ input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur

content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B may be used in lieu of CEMS to measure SO₂ at the inlet or outlet of the SO₂ control system. An initial stratification test is required to verify the adequacy of the Method 6B sampling location. The stratification test shall consist of three paired runs of a suitable SO₂ and carbon dioxide measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 (appendix B). Method 6B, Method 6A, or a combination of Methods 6 and 3 or Methods 6C and 3A are suitable measurement techniques. If Method 6B is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO₂ standards based on fuel supplier certification, as described under §60.48c(f) (1), (2), or (3), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

§ 60.47c Emission monitoring for particulate matter.

(a) The owner or operator of an affected facility combusting coal, residual oil, or wood that is subject to the opacity standards under §60.43c shall install, calibrate, maintain, and operate a CEMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system.

(b) All CEMS for measuring opacity shall be operated in accordance with the applicable procedures under Performance Specification 1 (appendix B). The span value of the opacity CEMS shall be between 60 and 80 percent.

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO₂ emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO₂ emission limits of §60.42c, or the PM or

opacity limits of § 60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS using the applicable performance specifications in appendix B.

(c) The owner or operator of each coal-fired, residual oil-fired, or wood-fired affected facility subject to the opacity limits under § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility which occur during the reporting period.

(d) The owner or operator of each affected facility subject to the SO₂ emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO₂ emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.43c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO₂ emission rate (nj/J or lb/million Btu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO₂ emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO₂ or diluent (oxygen or carbon dioxide) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective

actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 (appendix B).

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), or (3) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier; and

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in § 60.41c.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

(h) The owner or operator of each affected facility subject to a Federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under § 60.42c or § 60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[55 FR 37683, Sept. 12, 1990, as amended at 64 FR 7465, Feb. 12, 1999]

Subpart E—Standards of Performance for Incinerators

§ 60.50 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each incinerator of more than 45 metric tons per day charging rate (50 tons/day), which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

[42 FR 37936, July 25, 1977]

§ 60.51 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Incinerator* means any furnace used in the process of burning solid waste for the purpose of reducing the volume of the waste by removing combustible matter.

(b) *Solid waste* means refuse, more than 50 percent of which is municipal type waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustibles, and noncombustible materials such as glass and rock.

(c) *Day* means 24 hours.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 20792, June 14, 1974]

§ 60.52 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this part shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of 0.18 g/dscm (0.08 gr/dscf) corrected to 12 percent CO₂.

[39 FR 20792, June 14, 1974]

§ 60.53 Monitoring of operations.

(a) The owner or operator of any incinerator subject to the provisions of this part shall record the daily charging rates and hours of operation.

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(2) Each owner or operator of each storage vessel equipped with a vapor recovery and return or disposal system in accordance with the requirements of § 60.112a (a)(3) and (b).

[45 FR 23379, Apr. 4, 1980]

Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

SOURCE: 52 FR 11429, Apr. 8, 1987, unless otherwise noted.

§ 60.110b Applicability and designation of affected facility.

(a) Except as provided in paragraphs (b), (c), and (d) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 40 cubic meters (m^3) that is used to store volatile organic liquids (VOL's) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) Except as specified in paragraphs (a) and (b) of § 60.116b, storage vessels with design capacity less than 75 m^3 are exempt from the General Provisions (part 60, subpart A) and from the provisions of this subpart.

(c) Except as specified in paragraphs (a) and (b) of § 60.116b, vessels either with a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kPa or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa are exempt from the General Provisions (part 60, subpart A) and from the provisions of this subpart.

(d) This subpart does not apply to the following:

(1) Vessels at coke oven by-product plants.

(2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

(3) Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships.

(4) Vessels with a design capacity less than or equal to $1,589.874 \text{ m}^3$ used for petroleum or condensate stored, processed, or treated prior to custody transfer.

(5) Vessels located at bulk gasoline plants.

(6) Storage vessels located at gasoline service stations.

(7) Vessels used to store beverage alcohol.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.111b Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this subpart as follows:

(a) *Bulk gasoline plant* means any gasoline distribution facility that has a gasoline throughput less than or equal to 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal requirement or Federal, State or local law, and discoverable by the Administrator and any other person.

(b) *Condensate* means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

(c) *Custody transfer* means the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

(d) *Fill* means the introduction of VOL into a storage vessel but not necessarily to complete capacity.

(e) *Gasoline service station* means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks.

(f) *Maximum true vapor pressure* means the equilibrium partial pressure exerted by the stored VOL at the temperature equal to the highest calendar-month average of the VOL storage temperature for VOL's stored above or below the ambient temperature or at the local maximum monthly average

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temperature as reported by the National Weather Service for VOL's stored at the ambient temperature, as determined:

(1) In accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss From External Floating Roof Tanks, (incorporated by reference—see § 60.17); or

(2) As obtained from standard reference texts; or

(3) As determined by ASTM Method D2879–83 (incorporated by reference—see § 60.17);

(4) Any other method approved by the Administrator.

(g) *Reid vapor pressure* means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquified petroleum gases, as determined by ASTM D323–82 (incorporated by reference—see § 60.17).

(h) *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(i) *Petroleum liquids* means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery.

(j) *Storage vessel* means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include:

(1) Frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors; or

(2) Subsurface caverns or porous rock reservoirs.

(k) *Volatile organic liquid (VOL)* means any organic liquid which can emit volatile organic compounds into the atmosphere except those VOL's that emit only those compounds which the Administrator has determined do not contribute appreciably to the formation of ozone. These compounds are identified in EPA statements on ozone abatement policy for SIP revisions (42 FR 35314, 44 FR 32042, 45 FR 32424, and 45 FR 48941).

(l) *Waste* means any liquid resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, or biologically

treated prior to being discarded or recycled.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.112b Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(1) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be

vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel

with no fixed roof. Each external floating roof must meet the following specifications:

(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in § 60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.

(B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in § 60.113b(b)(4).

(ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

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(3) A closed vent system and control device meeting the following specifications:

(i) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, § 60.485(b).

(ii) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§ 60.18) of the General Provisions.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in § 60.114b of this subpart.

(b) The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m³ which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:

(1) A closed vent system and control device as specified in § 60.112b(a)(3).

(2) A system equivalent to that described in paragraph (b)(1) as provided in § 60.114b of this subpart.

(c) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site").

(1) For any storage vessel that otherwise would be subject to the control technology requirements of paragraphs (a) or (b) of this section, the site shall have the option of either complying directly with the requirements of this subpart, or reducing the site-wide total criteria pollutant emissions cap (total emissions cap) in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the total emissions cap in accordance with the procedures set forth in such permit, the requirements of such permit

shall apply in lieu of the otherwise applicable requirements of this subpart for such storage vessel.

(2) For any storage vessel at the site not subject to the requirements of 40 CFR 60.112b (a) or (b), the requirements of 40 CFR 60.116b (b) and (c) and the General Provisions (subpart A of this part) shall not apply.

[52 FR 11429, Apr. 8, 1987, as amended at 62 FR 52641, Oct. 8, 1997]

§ 60.113b Testing and procedures.

The owner or operator of each storage vessel as specified in § 60.112b(a) shall meet the requirements of paragraph (a), (b), or (c) of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of § 60.112b.

(a) After installing the control equipment required to meet § 60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

(2) For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be

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emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in § 60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with a double-seal system as specified in § 60.112b(a)(1)(ii)(B):

(i) Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years; or

(ii) Visually inspect the vessel as specified in paragraph (a)(2) of this section.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (a)(2) and (a)(3)(ii) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (a)(3)(i) of this section.

(5) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a)(1) and (a)(4) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (a)(4) of this section is not planned and the owner or operator

could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(b) After installing the control equipment required to meet § 60.112b(a)(2) (external floating roof), the owner or operator shall:

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.

(i) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.

(ii) Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.

(iii) If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(ii) Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of

this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4) (i) and (ii) of this section:

(i) The accumulated area of gaps between the tank wall and the mechanical shoe or liquid-mounted primary seal shall not exceed 212 Cm² per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

(A) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

(B) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (b)(2)(iii) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm² per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

(C) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) If a failure that is detected during inspections required in paragraph (b)(1) of § 60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in § 60.115b(b)(4). Such extension

request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(c) The owner or operator of each source that is equipped with a closed vent system and control device as required in § 60.112b (a)(3) or (b)(2) (other than a flare) is exempt from § 60.8 of the General Provisions and shall meet the following requirements.

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(1) Submit for approval by the Administrator as an attachment to the notification required by § 60.7(a)(1) or, if the facility is exempt from § 60.7(a)(1), as an attachment to the notification required by § 60.7(a)(2), an operating plan containing the information listed below.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(d) The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in § 60.112b (a)(3) or (b)(2) shall meet the requirements as speci-

fied in the general control device requirements, § 60.18 (e) and (f).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.114b Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in § 60.112b, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement.

(b) Any notice under paragraph (a) of this section will be published only after notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in § 60.112b.

§ 60.115b Reporting and recordkeeping requirements.

The owner or operator of each storage vessel as specified in § 60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of this section depending upon the control equipment installed to meet the requirements of § 60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

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(a) After installing control equipment in accordance with § 60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(1) and § 60.113b(a)(1). This report shall be an attachment to the notification required by § 60.7(a)(3).

(2) Keep a record of each inspection performed as required by § 60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in § 60.113b(a)(2) are detected during the annual visual inspection required by § 60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.

(4) After each inspection required by § 60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in § 60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of § 60.112b(a)(1) or § 60.113b(a)(3) and list each repair made.

(b) After installing control equipment in accordance with § 60.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(2) and § 60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by § 60.7(a)(3).

(2) Within 60 days of performing the seal gap measurements required by

§ 60.113b(b)(1), furnish the Administrator with a report that contains:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in § 60.113b (b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by § 60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in § 60.113b (b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by § 60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair.

(c) After installing control equipment in accordance with § 60.112b (a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

(1) A copy of the operating plan.

(2) A record of the measured values of the parameters monitored in accordance with § 60.113b(c)(2).

(d) After installing a closed vent system and flare to comply with § 60.112b, the owner or operator shall meet the following requirements.

(1) A report containing the measurements required by § 60.18(f) (1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by § 60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

(2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.

(3) Semiannual reports of all periods recorded under § 60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

§ 60.116b Monitoring of operations.

(a) The owner or operator shall keep copies of all records required by this section, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The owner or operator of each storage vessel as specified in § 60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel. Each storage vessel with a design capacity less than 75 m³ is subject to no provision of this subpart other than those required by this paragraph.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage

temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see § 60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(3) For other liquids, the vapor pressure:

(i) May be obtained from standard reference texts, or

(ii) Determined by ASTM Method D2879-83 (incorporated by reference—see § 60.17); or

(iii) Measured by an appropriate method approved by the Administrator; or

(iv) Calculated by an appropriate method approved by the Administrator.

(f) The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.

(1) Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.

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(2) For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:

(i) ASTM Method D2879-83 (incorporated by reference—see §60.17); or

(ii) ASTM Method D323-82 (incorporated by reference—see §60.17); or

(iii) As measured by an appropriate method as approved by the Administrator.

(g) The owner or operator of each vessel equipped with a closed vent system and control device meeting the specifications of §60.112b is exempt from the requirements of paragraphs (c) and (d) of this section.

§ 60.117b Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: §§ 60.111b(f)(4), 60.114b, 60.116b(e)(3)(iii), 60.116b(e)(3)(iv), and 60.116b(f)(2)(iii).

[52 FR 11429, Apr. 8, 1987, as amended at 52 FR 22780, June 16, 1987]

Subpart L—Standards of Performance for Secondary Lead Smelters

§ 60.120 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in secondary lead smelters: Pot furnaces of more than 250 kg (550 lb) charging capacity, blast (cupola) furnaces, and reverberatory furnaces.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

[42 FR 37937, July 25, 1977]

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§ 60.121 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Reverberatory furnace* includes the following types of reverberatory furnaces: stationary, rotating, rocking, and tilting.

(b) *Secondary lead smelter* means any facility producing lead from a leadbearing scrap material by smelting to the metallic form.

(c) *Lead* means elemental lead or alloys in which the predominant component is lead.

[39 FR 9317, Mar. 8, 1974; 39 FR 13776, Apr. 17, 1974]

§ 60.122 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from a blast (cupola) or reverberatory furnace any gases which:

(1) Contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any pot furnace any gases which exhibit 10 percent opacity or greater.

[39 FR 9317, Mar. 8, 1974, as amended at 40 FR 46259, Oct. 6, 1975]

§ 60.123 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the particulate matter standards in §60.122 as follows: